CHAPTER 2

RATEMAKING AND COST RECOVERY

CHRIS BLUNT

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I. COST RECOVERY AND BALANCING ACCOUNTS

A. SDG&E's Proposal

SDG&E's amended testimony, dated July 17, 2006, described the regulatory balancing account treatment for its proposed AMI revenue requirements for the years 2007 through 2011.[1] Between 2007 and 2011, SDG&E proposes to record and recover, per month and annually, the actual AMI Project costs and dollars per meter benefits through existing, and a new AMI, balancing accounts. SDG&E proposes to recover the incremental or net change in the revenue requirements associated with projected AMI deployment from its electric customers through electric distribution rates, and from its gas customers through gas transportation rates. The net changes would be allocated in proportion to the number of AMI meters planned to be installed per customer class. SDG&E proposes to continue this allocation methodology until its next marginal cost studies. Since 2011 is the last year for which SDG&E provided AMI estimated costs, SDG&E will include AMI recovery in its Test-Year 2012 General Rate Case filing.

Revenue over- or under-collected from the CPP rate design[2], and costs associated with fuel and purchased power would flow through SDG&E's Energy Resources Recovery Account ("ERRA"), while all other generation costs will flow through the Non-Fuel Generation Balancing Account ("NGBA") in the same way as other revenues do in the generation portion of the standard tariffs. CPP

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[1] No material changes from SDG&E's March 28, 2006 AMI Application.

[2] Including all future CPP participation credits, and first-year bill protection.

program costs are currently recovered through the Advanced Metering and Demand Response Account ("AMDRA"). SDG&E proposes to allocate costs associated with its Peak Time Rebate ("PTR") program using currently-adopted Distribution allocation factors. D.05-12-003[3] authorized SDG&E's current Equal Percent of Marginal Cost ("EPMC") methodology for its distribution revenue requirement.

B. DRA's Recommendation

DRA does not object to the proposed balancing account treatments discussed above, except for the treatment of CPP program costs and PTR program rebates booked to the AMDRA. These costs are demand response related, and therefore are best allocated using a generation capacity cost allocator.[4]

DRA objects to how the electric AMI costs would be allocated to electric customers. DRA finds that operational benefits of SDG&E's current AMI proposal are only 56% of costs. Thus, in order for the project to have a benefit-cost ratio equal to or greater than one, the demand response benefits would have to be at least 44%. Thus, if the Commission approves SDG&E's AMI request, DRA recommends that 44% of the total AMI project costs be allocated using generation capacity EPMC.

The rationale for DRA's proposed allocation is that the demand response benefits that would have to be used to justify 44% of the project cost are inherently demand-related. Thus this portion of the project costs should be allocated the same way that the corresponding demand response benefits would flow to

[3] SDG&E's latest Rate Design Window proceeding.

[4] This allocation is consistent with how the revenue shortfalls from SDG&E's proposed default CPP program would be allocated. SDG&E states that such shortfalls are picked up in the ERRA, and ERRA costs are allocated using generation allocators. (See SDG&E's July 14th update, page RHW-7.

customers. This hybrid allocation scheme should be applied to the electric AMI costs only since there are no gas demand response benefits.[5]

The remaining 56% of costs would be allocated using distribution EPMC under DRA's proposal. SDG&E allocated all AMI costs by meter installation costs by class. DRA did not use this allocator for the remaining 56%. This is because the existing distribution EPMC allocators better reflect how the majority of the utility's existing revenue requirement that are associated with the AMI operational benefits would normally be allocated.

DRA's resulting allocation of the electric AMI system costs are shown in Table 2-1.[6]

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[5] DRA has quantified gas conservation benefits from information feedback, but they are relatively small compared to demand response benefits and thus being ignored in this allocation proposal.

[6] To calculate the electric allocators, DRA first calculated 39% of the total electric and gas 2007 – 2011 AMI revenue requirement, and then subtracted this from the electric 2007 – 2011 AMI revenue requirement. The result was allocated based on electric meter installation costs. The rest was allocated based on electric generation EPMC.

TABLE 2-1
ALLOCATION OF ELECTRIC AMI NET COSTS

Customer Class	SDG&E's Proposal	DRA's Recommendation
Residential	63.79%	46.78%
Small Commercial	30.27%	13.32%
Medium and Large C&I	5.08%	39.24%
Agricultural	0.87%	0.49%
Street Lighting	0.00%	0.17%
Total	100.00%	100.00%

In PG&E's AMI Proceeding, PG&E proposed to allocate AMI costs by distribution EPMC factors. DRA did not dispute PG&E's recommendations since most (89%) of PG&E's AMI costs were offset by operational benefits. In this case, only 56% of AMI costs are offset by operational benefits, thus DRA proposes a hybrid allocator that reflects both system cost savings and demand response benefits. Furthermore, PG&E used distribution EPMC to allocate AMI costs rather than the meter installation costs by class. Using distribution EPMC allocates fewer costs to small customers than does meter installation costs by class.

In this case DRA uses gas distribution EPMC to allocate gas AMI costs for similar reasons for why electric distribution EPMC was used to allocate part of the electric AMI costs. SDG&E did not allocate any costs to non-core gas customers because they currently have metering capabilities enabled with Automated Metering Reading ("AMR") devices. DRA does not agree with this reasoning. All metering devices become part of the distribution revenue requirement and are allocated to all customers. Thus, all customers have been paying for the existing AMR devices serving SDG&E's non-core gas customers. When the rest of the system receives such meters, the treatment should be the same. They should be paid by all customers and allocated using the EPMC factors normally used for such capital costs.

DRA's resulting allocation of the gas AMI system costs are shown in Table 2-2.

TABLE 2-2
ALLOCATION OF GAS AMI NET COSTS

Customer Class	SDG&E's Proposal	DRA's Recommendation
Residential	93.17%	77.42%
Core C&I	6.82%	10.57%
NGV	0.01%	0.33%
Total Core	100.00%	88.32%
Noncore C&I	0.00%	11.33%
Total	100.00%	99.65%

DRA recommends that, regardless of how electric and gas costs are allocated, they should be recovered through electric distribution rates and gas transportation rates. This way all customers, including those who do not purchase their electric and gas commodities through SDG&E, but who receive SDG&E meter reading services, will pay for AMI.[7]

II. COST OVERRUNS

To ensure that ratepayer benefits are not negated due to cost overruns, DRA recommends that the Commission either include a firm cap on all AMI Project costs, or alternatively hold SDG&E shareholders responsible for 10% percent of any cost overruns totaling up to $50 million, with cost overruns over $50 million being subject to reasonableness review. Details of this recommendation are discussed in Chapter 3 (Irwin).

In D.06-07-027 the Commission approved a stipulation between DRA and PG&E that 90 percent of up to $100 million in AMI Project costs beyond the $1.6846 billion, if any, would be deemed reasonable and recovered in rates without any after-the-fact reasonableness review. The remaining 10 percent will be absorbed by shareholders. Also, Costs in excess of $100 million over the $1.6846 billion will be recoverable only if approved by the Commission in a reasonableness review.[8]

[7] DRA recognizes that its allocation proposal will result in electric direct access customers paying for the portion of the AMI costs associated with demand response benefits. Though such customers do not receive direct benefits from demand reductions on SDG&E's system, they receive indirect benefits in that the whole regional market benefits from freeing up supply-side resources. Also, if there is a blackout because of inadequate generation resources, these customers will be blacked out as well.

[8] Similar to the settlement between DRA and PG&E on costs relating to PG&E's construction of the Contra Costa 8 power plant. That settlement provided for an incentive to avoid cost overruns, which eliminated the need for an after-the-fact reasonableness review unless cost overruns exceed a threshold amount.

III. REPORTING REQUIREMENTS

DRA recommends SDG&E be required to make filings with the Commission, at least quarterly, providing information on the current status of the AMI rollout including progress towards AMI Project milestones and AMI deployment schedule, the amount of actual AMI Project spending versus forecast costs, and actual installations compared to the proposed schedule.

IV. CONCLUSION

DRA does not object the proposed balancing account treatments discussed above, except for the treatment of CPP program costs and PTR program rebates booked to the AMDRA. DRA recommends that 56% of electric AMI costs be allocated by distribution EPMC factors and 44% be allocated by generation EPMC factors and that gas AMI costs are allocated by gas distribution EPMC factors. DRA recommends SDG&E file quarterly status reports on its AMI Project, and that its shareholders share in any AMI Project cost overruns.